NON-PUBLIC?: N
ACCESSION #: 9505240181
LICENSEE EVENT REPORT (LER)

FACILITY NAME: Oconee Nuclear Station, Unit 2 PAGE: 1 OF 6

DOCKET NUMBER: 05000270

TITLE: Incorrect Timer Setting Due To A Design Deficiency
Results In A Reactor Trip
EVENT DATE: 04/14/95 LER #: 95-02-00 REPORT DATE: 05/15/95

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: N POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
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COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On April 14, 1995, at 09:59:24 hours, Unit 2 reactor tripped from 100% full power on a Reactor Protective System turbine anticipatory trip signal due to a generator lockout. A generator protective relay circuit actuated due to a fault that occurred on the system grid, followed by a breaker failure located in an offsite substation. Post trip response was normal. An investigation revealed that a timer on the protective relay had been incorrectly set for .8 seconds instead of 10 to 60 seconds as recommended by the manufacturer. The root cause of this event was determined to be Design Deficiency, functional design deficiency, electrical. Corrective action includes the design and implementation of a modification for all three units to replace the timer on the protective relay and setting the timer between 10 and 60 seconds.

END OF ABSTRACT

BACKGROUND

The electrical generator EIIS:GEN! uses protective relaying to sense abnormal conditions that may adversely affect the generator. when this condition is sensed, it produces a lockout that will open the main generator breakers and trip the turbine. One of the protective relays is a 40-2 (Loss of Excitation).

A turbine trip will produce a reactor trip when power is greater than 30 percent by actuating Reactor Protective System EIIS:JC! turbine anticipatory trip channels. The purpose of this trip is to limit Reactor Coolant System EIIS:AB! pressure and prevent challenging the Power Operated Relief Valve following a turbine trip.

Technical Specifications require that the maximum Control Rod trip insertion time for an operable Control Rod Drive Mechanism (EIIS:AA! shall not exceed 1.66 seconds, from fully withdrawn to 3/4 insertion (104 inches of travel).

EVENT DESCRIPTION

On April 14, 1995, at approximately 09:59 hours, a transmission fault occurred on the Pickens Black 100 Kv transmission line which is part of the Duke Power distribution system.

At 09:59:24 hours, Unit 2 reactor tripped from 100% full power on a Reactor Protective System turbine anticipatory trip signal due to a generator lockout following a loss of excitation. All full length control rods fully inserted into the core and the reactor was shutdown.

The Operators confirmed that the Reactor and Turbine had tripped and monitored for proper operation of other automatic equipment. The Operators entered the Emergency Operating Procedures, and as normally required after a Reactor trip, manually started an additional High Pressure Injection (HPI) EIIS:BG! pump at 10:00:06 hours, and opened HPI Emergency Make-up Valve to increase HPI flow to maintain Pressurizer level. At 10:02:56 hours, the operator closed the valve and then secured the HPI pump.

Following the reactor trip, the average Reactor Coolant System (RCS) EIIS:AB! temperature decreased from 579 F to 555 F and the RCS pressure decreased from approximately 2148 psig to 1815 psig. Pressurizer level decreased from 222 inches initially to a minimum of 61 inches and stabilized at 153 inches. Steam Generator (SG) "A" pressure increased to a maximum of 1133 psig and decreased to a minimum of 972 psig. SG "B" pressure increased to a maximum of 1126 psig and decreased to a minimum of 970 psig. Both SG levels decreased to a minimum of 21 inches before stabilizing at 25 inches. As systems and operators responded to the trip, RCS pressure reached a maximum of 2181 psig and stabilized at approximately 2176 psig.

During the process of securing the 2B Main Feedwater Pump (MFDWP), the 2A MFDWP tripped at 10:26:26 hours, due to low oil pressure. Operators observed the problems and terminated the shutdown of the 2B MFDWP. A work request was generated to investigate the cause of the 2A MFDWP trip. The initial cause was determined to be a clogged strainer. The strainer was cleaned and the pump was returned to service. This problem was entered into the Problem Investigation Process (PIP) for further investigation.

The post-trip review revealed that Group 2 Rod 6 of the Control Rod Drive (CRD) System had a drop time of 1.842 seconds. This rendered the rod inoperable. This problem was entered into the Problem Investigation Process to be evaluated by Engineering. On April 15, 1995, prior to startup of Unit 2, an operability evaluation was performed by Engineering. The evaluation concluded that Unit 2's CRD System was past and presently operable because the condition of one inoperable control rod is fully analyzed and is an allowed condition. This CRD was subsequently repaired during a forced outage.

An investigation into the cause of the trip revealed that prior to the trip a transmission-fault occurred on the Pickens Black 100 Kv transmission line. A two phase to ground fault occurred when a lumber company cut a tree that fell on the line. The 100 Kv system breaker (located in the Greenlawn substation) that should have cleared this fault failed to trip due to a failed trip coil. Subsequently, the fault was cleared by breakers at the Central and North Greenville substations. The failed breaker was not equipped with breaker failure protection to rapidly trip the upstream breakers. Therefore, the fault remained connected to the system for the time it took the upstream protective devices to detect and initiate protective trips (approximately 1.2 seconds).

Further investigation revealed that a timer (62LF) on the loss of excitation relay (40-2) that provides rotor thermal protection for the generator was set incorrectly (.8 seconds). The range of the timer was from .2 to 4 seconds. An elementary diagram of Unit 1 and 2's main relaying was revised on October 24, 1974, to add the loss of excitation

relay and timer. A review of the Vendor Manual (Westinghouse I.L. 41-748.1C Effective April 1971) indicated that this timer should be set between 10 and 60 seconds. The timers on Units 1 and 3 are also set at .8 seconds. This circuitry is not safety related. No further documentation was found on the installation of the relays and timers.

CONCLUSION

The cause of the reactor trip was due to a fault on the grid in conjunction with a breaker failure in a substation and incorrect timer setting on the loss of excitation relay. If the proper timer range had been used, the fault would have cleared prior to relay actuation and the reactor trip would have been prevented. During the modification process the incorrect timer setting was selected, possibly due to a misinterpretation of Vendor Manual information. This resulted in the installation of the incorrect timer. Therefore, the root cause of this event was determined to be a Design Deficiency, functional design deficiency, electrical.

A review of LERs written within the last two years revealed that four events (269/93-04, 269/94-01, 269/94-04 and 269/95-03) involved Design Analysis, unanticipated interaction of systems or components. LER 269/9304 involved a potential single failure that could close all Condenser Circulating Water EIIS:BS! Pump Discharge Valves on single unit following a Loss of Coolant Accident/Loss of Offsite Power. LER 269/94-01 involved a potential seismic interaction that could have resulted in the loss Emergency Condenser Circulating Water. LER 269/94-04 involved a postulated event that may have rendered the Post Accident Core Cooling system inoperable. LER 269/95-03 involved a potential single failure that could have resulted in exceeding the Equipment Qualification requirements. All four of the events identified above involved design deficiencies; therefore, the event is considered to be recurring. The corrective actions for the events identified above included modifications, completion of single failure analysis and Design Basis Documents. Because this event occurred prior to the discovery of the problems reported by those LERS, the associated corrective actions could not have prevented this event. Enhancements to the design process since 1974 should prevent this type of design deficiency in the future.

The generator lockout relay actuation is NPRDS reportable, but there were no NPRDS reportable equipment failures. The manufacturer is General Electric and the model number is SATI851172A1. The event did not result in personnel injuries, radiation overexposures, or releases of radioactive materials.

CORRECTIVE ACTIONS

Immediate

1. Operators took appropriate actions to stabilize the unit at hot shutdown.

Subsequent

1. A modification has been installed on Unit 1 which replaced the 62-LF timer on the loss of excitation relay and set the timer for 30 seconds.

Planned

1. Design and implement a modification for Unit 2 to replace the 62-LF timer on the loss of excitation relay and set the timer between 10 and 60 seconds.

2. Design and implement a modification for Unit 3 to replace the 62-LF timer on the loss of excitation relay and set the timer between 10 and 60 seconds.

3. A review will be performed by Engineering to ensure that other relay timers in the Main Power and Switchyard protective relaying applications at Oconee (which includes Keowee) are set as required.

SAFETY ANALYSIS

A loss of generator load and the resulting turbine trip, while at power operation, leads to an imbalance between the amount of heat produced in the primary system and the amount of heat removed by the secondary system. The Reactor Protective System (RPS) prevents excessive Reactor Coolant System

(RCS) overpressurization and heatup by the actuation of the turbine trip anticipatory reactor trip. The RPS operated as designed and tripped the reactor. The plant post-trip response was normal except for the following:

Steam Generators A and B post-trip pressures were considered slightly higher than normal, but Main Steam Relief valves adequately controlled pressure such that design pressure was not exceeded.

One control rod did not drop within the time frame specified by the Technical Specification. This condition is fully analyzed and allowed by the Technical Specifications.

No Engineered Safeguards System or Emergency Feedwater actuations were either required or received. The health and safety of the public were not compromised by this event.

ATTACHMENT TO 9505240181 PAGE 1 OF 1

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DUKE POWER

May 15, 1995

U. S. Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Subject: Oconee Nuclear Station
Docket Nos. 50-269, -270, -287
LER 270/95-02

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a)(1) and (d), attached is Licensee Event Report (LER) 270/95-02, concerning a Reactor Trip.

This report is being submitted in accordance with 10 CFR 50.73 (a)(2)(iv). This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

J. W. Hampton
Vice President

/dlb

Attachment

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